Using Operating Data at Natural Gas Pipelines

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INTRODUCTION

Interstate natural gas pipelines are operated using sophisticated supervisory control and data acquisition (SCADA) systems. These systems are used to monitor, control and analyze operations. Software which runs in conjunction with the basic SCADA system expands the usefulness of SCADA data to enhance reliability and efficiency of operations, improve customer service, and minimize undesirable business practices, all in near real-time. Data from such systems are used off-line for the development of planning tools, training and system design studies.

PIPELINE OPERATIONS OVERVIEW

Operating under the jurisdiction of the U. S. Federal Energy Regulatory Commission, interstate pipelines provide open access for shipment of natural gas. Gas enters an interstate pipeline from gathering systems and from interconnecting pipelines. Beginning at individual wellheads, gathering systems usually consist of smaller diameter pipe operating at lower pressure. Gas conditioning is usually performed to reduce contaminants such as water from gathered gas before it is compressed into the transmission system. Gas leaves the transmission system through delivery points to other interstate pipelines, local distribution companies and directly to end users such as industrial facilities and power plants. Local distribution systems deliver gas to residential, commercial and industrial end users.

The basic components of an interstate pipeline include steel pipe, valves, compression, processing and storage facilities. Pipe sizes vary widely with much of the pipe in the 20-inch to 36-inch diameter range and wall thickness of about one-quarter to one-half inch. A typical range of operating pressures for a transmission system is 300 to 1440 psig. Powered by natural gas or electricity, compression is one of two types: reciprocating or centrifugal. Processing facilities extract undesirable contaminants (such as hydrogen sulfide and water) and marketable hydrocarbons (such as propane and gasoline). Storage facilities have been developed from depleted oil fields, coal mines, salt domes, aquifers and reefs. These facilities can be used for peak-shaving hourly demands and short-term, as well as, seasonal storage of gas.

Much of the gas that is transported on interstate pipelines is nominated, that is, scheduled in advance of actual gas flow. Deliveries into local distribution companies that serve weather-sensitive markets, however, cannot be known with absolute certainty. Such demand is met in part with “no-notice” service, which is usually supplied from inventories of the customers’ gas, which is stored in the pipeline’s storage facilities.

OPERATIONAL DATA

Gas pipelines are operated with a three-fold objective of ensuring safety of persons and property, reliability of service and cost-effectiveness. Operations are monitored and controlled by use of SCADA systems that provide thousands of data to pipeline controllers and operators. Some data are provided at intervals of a few seconds, other data are provided at intervals of a few minutes and still others on an hourly or daily basis.

Operational data include pipeline pressure, flow rate, gas composition, and equipment status. Maintaining appropriate pressures in the pipeline is essential to ensure safety, maximize throughput and provide reliability of service. Flow rates are determined on the basis of energy as well as volume and are used to balance system demands and supplies. Gas composition is required to maintain appropriate combustion characteristics, screen for undesirable contaminants, and balance gas transmission on a thermal basis. Equipment status, such as valve position and compressor information, is used to confirm that the system is configured to meet operational objectives.

SCADA SYSTEMS

SCADA system designs vary widely but there are elements common to all. For an interstate pipeline, data must be gathered from locations that are distributed widely across large geographical areas. Measurement transducers are polled frequently, often every two to five minutes. In a limited number of highly critical operations that are performed on-site at field locations, polling frequencies are measured in seconds. To efficiently perform basic functions, data must be accessible by operations personnel located in the field and at a central pipeline control center. As data are updated, the older data that have been superceded over time must be stored for audit trails, trending, and maintaining a historical operating record.

HARDWARE

SCADA systems are configured with a variety of instrumentation. Flow rates can be measured using orifice plates, annubars, or ultrasonic measurement devices. Gas quality is measured using thermal titration or gas chromatography. Where necessary, instrumentation is installed to sample for various contaminants including oxygen, water, and hydrogen sulfide.

Electrical signals from measurement devices are typically converted to engineering units in computers, referred to as remote terminal units (RTU), which are located at the measurement site. Communication links are provided by radio, cell phone, private microwave, leased line or satellite. Polling frequencies can be predetermined or on-demand.

Data from a given area of operations is often concentrated in computers at field offices, which are distributed throughout the pipeline system. SCADA software running on these field computers provides operational data and control to local operations personnel. Central computers located at a company’s pipeline control center, in turn, poll field computers. SCADA software runs on the central computers to provide pipeline controllers with displays of operational data and remote control capabilities.

LEVEL OF INSTRUMENTATION

For locations where gas is received or delivered, the level of instrumentation and telemetry is often dependent upon volume rates. At low rates, e.g., below 1 MMcf/d, gas flow is recorded locally but not telemetered by way of the SCADA system. At somewhat higher rates, pressures and flow rates are recorded locally and telemetered via the SCADA system. Above a certain threshold, perhaps 5 MMcf/d, pressures, flow rates, and gas quality are continuously measured and telemetered via the SCADA system.

Measurement facilities, hence SCADA data, are located at points where gas is received and delivered, at compressor stations, and at other remotely actuated equipment such as valves. Distribution of measurement points is thus facility-driven and is rarely uniform across the system; that is, measurement is not generally installed at regular increments of pipeline length.

DATA PRESENTATION

With so much data available at such high frequency, the effectiveness of the SCADA system hinges on appropriate data presentation, analysis and alarming. A variety of data presentations are used to transform basic data into information. Trends, schematics and other graphics are used to convey large amounts of data, which vary over time, in a concise and informative format.

TABULAR

Original SCADA systems made extensive use of tabular formats for data presentation. If the objective is to maximize the amount of data on one screen, tables of numbers are a good way to do it. Apart from being visually boring, tables can be difficult to decipher. New employees often struggle to put tabular data in the appropriate spatial and operational context.

SCHEMATICS

Superimposing operational data on facility schematics is an alternative method of data presentation. While potentially less efficient than tables in the use of screen space, schematic presentation offers several advantages. New employees can more easily put data in the appropriate operational context. Internal consistency of data can be assessed more readily. Color schemes can be used to convey equipment status, e.g., red for closed/off and green for open/on. With pipelines and color coded valves indicating open and closed positions, flow paths are more readily apparent. Managing emergencies is facilitated by presenting receipt and delivery information in the context of operating equipment such as compression and valves, which are used to mitigate the impacts of emergencies.

In some SCADA system installations, file compatibility has been established between SCADA system displays and standard drafting software. Using files developed by a firm's drafting or GIS department offers numerous advantages, not the least of which is, the most recent revisions of drawings can be put to immediate use by operating personnel. Current schematics are essential to the effective management of all pipeline operations from routine daily operations to emergencies.

TRENDING

Ambient temperature fluctuations lead demand profiles where weather-sensitive loads are served. This is but one example of another effective means of data presentation, namely, trending. Trends are especially useful in monitoring pipeline operations because the vast majority of data, including flow rates, pressures and gas quality continuously vary with time. Trends are useful in assessing what has happened and in projecting what might happen. In an emergency situation, trends are extremely useful in corroborating incident reports and providing initial indications of affected locations.

REAL-TIME ANALYSES

SCADA systems are designed to provide for continuous calculations using telemetered quantities. Combining multiple data into meaningful aggregated and calculated quantities provides an effective means of synthesizing data and conveying information. Key aspects of pipeline operation can thus be quantified and trended. The pipeline controller is relieved of reviewing large amounts of raw data, performing calculations, keeping log sheets and making inferences. More of the controller's time can be spent analyzing current operation, making projections and proactively coordinating system changes.

SYSTEM BALANCE

Many pressure measurements are combined with the physical description of the pipeline to render the inventory of gas in the pipeline as a whole and in its various segments. The result is called linepack, and this one number conveys much information about the state of the pipeline. A mid-size interstate pipeline consisting of 3000 to 5000 miles pipe in the 20-inch diameter range will contain two to three billion cubic feet of linepack. As much as five to ten percent of linepack may be available for packing or drafting, i.e., increasing or decreasing gas inventory in the pipeline. Used in such a way, linepack provides a significant amount of short-term storage.

Interstate pipelines have hundreds of locations where gas volumes are received and delivered. Aggregating some or all of these receipt volumes and delivery volumes provides essential information about the "balance" of the system and the performance of key segments. Trending the total receipts and total deliveries, along with system linepack, provides pipeline controllers with a near real-time system balance. Such information can be used to assess the proper level of storage field activity versus linepack utilization.

PIPELINE PERFORMANCE

When pressures at both ends of a pipeline segment are known, standard steady-state pipeline flow equations can be used to estimate flow through that segment. Comparisons between theoretical and measured gas flow allow for real-time assessment of pipeline performance. Gas flow equations for pipelines include a term such as roughness, typically in microinches, or efficiency, typically in percent. These terms have been empirically derived for new "smooth" pipe.

Flows that are calculated for ideal conditions can be used as a benchmark for performance analyses. Over time, contaminants in the gas stream are either deposited on the wall of the pipe or, in the case of liquids, settle into low spots, creating excessive pressure losses, thereby degrading the performance of the pipeline. Measured gas flow inherently describes the actual, somewhat degraded, performance of the pipeline. A simple comparison with the appropriate benchmark provides information that can be used to schedule cleaning of the lines. Predetermined limits can be established such that when the measured flow through the pipeline segment falls, say, 10 percent below "ideal" conditions, cleaning is mandated. The tolerance might be narrowed for pipelines operating at or near capacity and widened for slack lines.

Comparisons between calculated and measured flow rates can indicate, in extreme cases, the formation of blockages such as a line freeze or stuck pig. ("Pig" is a rather humorous moniker applied to devices used for cleaning and internal inspections of pipelines. One story has it that the original devices made a squealing noise as they exited the pipeline. Another story is that the name refers to the appearance of the devices as they were originally designed, however, devices currently in use have shapes ranging from spheres to torpedoes. Regardless, even veteran pipeliners have to smile at the images conjured up by "pig launchers" and "stuck pigs".) Freezes are the result of a combination of hydrocarbon vapor and water vapor entrained in the gas stream. Otherwise minor restrictions in flow can cause enough pressure reduction and corresponding temperature drop to precipitate liquid formation which in turn freezes. Using trends, departures between measured and calculated flow rates are graphically and effectively presented to pipeline controllers so that accurate problem identification can be made.

GAS BLENDING

"Natural gas" is a generic term applied to a mixture of hydrocarbon gases, with methane as the predominant constituent. Most natural gas contains at least some impurities. Quality specifications, which are detailed in an interstate pipeline's tariff, are established to protect the pipeline and compression against physical damage and performance degradation. When tolerances for impurities are exceeded, decisions must be made as to how much, if any, gas of substandard quality can be accepted.

Volumetric flow rates and gas qualities obtained from the SCADA system can be used to predict the gas quality of blended streams. As gas quality problems are encountered, expected blends can be calculated. While not always chemically correct, simple volume-weighted averages often provide reasonable estimates for operational decisions. Allowable flow rates from an offending source can thus be estimated based upon the concentration of contaminant relative to the volume and quality of the stream with which it will be blended. Such an approach protects the pipeline, minimizes disruption to production and can materially assist a producer or processor as they remedy gas quality problems.

ALARMS

Alarms are used to indicate that operating conditions are approaching or have exceeded prescribed tolerances. Attention can then be focussed on problem diagnosis and appropriate actions. However, too many minor alarms can have the reverse effect by desensitizing pipeline controllers to all alarms, important and trivial.

BASIC

Basic alarm types include high and critical high alarms, low and critical low alarms, and changes of status (on or off, open or closed). High limits can be applied to any type of data but are most often used for pressures and gas quality problems. Low limits are typically used for delivery pressures and volumes, particularly when volumes trend to zero. Status change alarms alert pipeline controllers to changes in system configuration. Changes may include an increase in compression, redirection of gas flow, or changes to gas quality.

The next level of alarm sophistication includes “rate of change” alarms. Abnormal variation of data with respect to time, such as a sudden increase or decrease of pressures, can trigger rate of change alarms. While data may not be high or low enough to trigger a basic alarm, unusually rapid fluctuation in value can indicate abnormal operating conditions. Major pipeline incidents are often detected quickly with appropriately set rate of change alarms.

ADVANCED

A third level of sophistication includes conditional alarms, which combine multiple data to warn the controller of specific abnormal conditions or to eliminate some nuisance alarms. An example is alarming gas quality which exceeds prescribed tolerances only when the receipt volume is non-zero. It makes little sense to issue a gas quality alarm for a source that is flowing no gas.

The most sophisticated alarms require numerous calculations involving multiple data points. Using near real-time analyses of pipeline performance, alarms can be employed to detect abnormal pressure drops associated with flow restrictions. Excess pressure loss would equate to higher calculated flow rates through the pipeline as compared to measured flow rates. Significant differences between calculated benchmark flow rates and measured flow rates can indicate some type of obstruction, such as hydrate formation or some other degradation in pipeline performance.

PIPELINE CONTROL

Pipeline operations are managed with a balance of automated and mechanical devices that are operated with local and remote control. For the most part, pipelines are controlled by regulation of pressure and volume through the use of compression and modulating valves. Pipeline facilities are protected from overpressure through the use of mechanical relief valves, which are completely independent of any control systems, including the SCADA system.

Volumes for receipt and many delivery points are set with modulating valves, often by remote control from the pipeline control center. Locations at which deliveries are made to local distribution companies, which serve weather-sensitive demand, are controlled locally with mechanical pressure regulation. The delivery pressure is maintained at nearly constant levels while demand varies significantly throughout the day. Delivery pressures are monitored and alarmed to ensure reliability but there is typically no remote control to such locations.

Compression is controlled with a combination of local and remote control. Suction or discharge pressures are determined for compressor stations based upon scheduled throughput. Pressure setpoints are sent from the pipeline control center to individual compressor stations via the SCADA system. The setpoints are relayed to local station automation equipment, which select units and set their speed and loading. As discharge pressures approach maximum allowable operating levels, local automation equipment slows and subtracts units as necessary.

LEAK DETECTION AND RESPONSE

Pipeline ruptures are rare and often the result of unreported third-party damage. They are very noisy affairs as gas at 500 to 1000 psig is blown to atmospheric pressure. The noise rapidly draws the attention of any people in the area. The first notification of such a pipeline incident is frequently a phone call from someone near the incident site. (Pipeline markers, which are liberally distributed along the pipeline right of way, provide the telephone number of the central pipeline control office.) Meanwhile on the SCADA system, the first indications of a problem include a rapid loss of pressure at nearby points. Rate of change alarms are typically issued by the SCADA system. Pipeline controllers usually identify incidents of this magnitude rapidly. Confirmation comes in the form of a phone call from an eyewitness and the receipt of additional scans that are sufficient to develop a trend.

RESPONSE

Responding to a rupture involves calling local field personnel and directing them to the block valves upstream and downstream of the site. If the site is located in an area of the pipeline where valves can be remotely actuated, the SCADA system can be used to isolate the damaged segment. After field personnel positively identify the location of the rupture site, pipeline controllers can be directed to remotely close valves immediately upstream and downstream of the rupture site. In areas where valves cannot be actuated through the SCADA system, operations personnel must travel to appropriate valves and isolate the damaged segment.

Some interstate transmission pipelines have installed “excess flow valves” which sense abnormal changes in flow and automatically close. In theory these locally controlled valves offer the fastest response time to isolation of the affected segment. Experience has shown, however, that these valves close in error as much or more than they close at appropriate times. When these valves are located immediately downstream of compression facilities they can pose as much hazard as help.

REAL-TIME SIMULATION

Coupling simulation results from real-time models with SCADA system data has long been proposed as an effective means to detect pipeline leaks [1]. Real-time models are a special application of simulation programs that describe transient pipeline operation as opposed to steady-state analyses. These simulation programs run in “lock-step” with pipeline operations as described by SCADA data. Deviations of simulated results from measured results can indicate leaks or errors in SCADA data.

The advantages of using a real-time transient model over a steady-state model for leak detection include a wider range of application and increased sensitivity. No longer must steady-state conditions apply as real-time models can be extended to cover the entire range of operating conditions. Sensitivity to detect smaller leaks is improved because systematic departures between calculated and measured results can be tracked through continuous operation.

While real-time models have been proposed for leak detection for some time, their application at gas pipelines has been very limited. Building and maintaining such a model is labor intensive. Response time for pipeline ruptures cannot be shortened appreciably and improvements in detection of small leaks will be limited by the extent to which a pipeline is instrumented. Measurement spacing is a factor in leak detection sensitivity. Miles of uninstrumented pipeline typically lies between clusters of measurement sites. Finally, where numerous small receipt and delivery points are not instrumented to provide pressure and flow data to the SCADA system, as is frequently the case, detection sensitivity is further eroded. The expense of the simulation program, additional telemetry and the resources to maintain both is simply not justified in many instances.

ACCIDENT PREVENTION

The excellent safety record of interstate pipelines is not a matter of chance. System designs are conservative with maximum allowable operating pressures mandated to be considerably below the yield strength of the pipe. Simple but effective pressure relief devices vent gas to prevent overpressure situations. Compressor station controls throttle back horsepower as pressure approaches the maximum allowable. Pipeline controllers schedule volumes and adjust system operations to avoid excessive pressure.

Pipeline companies aggressively pursue corrosion prevention. Gas quality specifications are established to prevent internal corrosion. Gas composition is monitored with the SCADA system and sources of potentially corrosive contaminants are limited in their flow rates, if not, shut in altogether. The exterior of pipelines is coated with corrosion inhibiting materials and cathodic protection is used extensively.

Most pipeline damage is caused by third parties encroaching on pipeline right-of-way. Damage prevention activities include public education efforts and encouragement to use “one-call” systems for the location of buried utilities, including gas pipelines. Field personnel on the ground and from the air routinely perform surveillance of pipeline right-of-way. Internal pipeline inspections are performed by smart pigs, which pinpoint locations of anomalies in the pipe wall. SCADA systems have little or no role in such accident prevention efforts.

In a limited number of applications, SCADA systems can be employed to alert pipeline controllers of a potential for pipeline failure. When a pipeline is located in an area of potential landslide, washout, or fault lines, instrumentation can be installed to provide early warning of soil movement and excessive strain on the pipeline. One approach involves the installation of strain gages directly on the pipeline. When telemetered values exceed the allowable tolerance, alarms are issued by the SCADA system so that appropriate action can be taken.

Research has been done to develop sensors to be used with appropriate signal conditioning and analysis to detect damage as it occurs. Even more ambitious are efforts to detect impending damage due to excavation near the pipeline. Presumably, such information would be communicated to pipeline controllers through the SCADA system. While promising, these efforts still have technical challenges to overcome. For a technical review of the subject see Francini et al. [2,3].

PLANNING AND SCHEDULING

For pipelines that serve weather-sensitive demand, load forecasting is an integral part of planning daily operations. Archived SCADA data, specifically flow rates, for deliveries into weather-sensitive areas are correlated with ambient temperature, wind speed and other weather variables. The resulting correlations are then used with weather predictions to quantify expected hourly and daily demand.

Currently, shippers can nominate their gas transactions four times per day. At the close of each nominating cycle, the demands for capacity on all segments of the pipeline are assessed with simple network models. Nominations are scheduled up to the sustainable capacity of the pipeline. Capacity limitations are determined by experience and review of historical SCADA data. Minor facility problems on the pipeline and on interconnecting systems will combine to render sustainable capacity somewhat below theoretical limits. To schedule volumes at theoretical limits is to invite the accrual of significant shortfalls from nominated levels.

In some instances, computer simulations are used to predict the pipeline system's physical response to expected demand and supplies. Simulation results are used to assess the feasibility of proposed operating plans. A key step in the simulation process is the comparison of recent SCADA data to calculated results. Based on these comparisons, modeling parameters are adjusted until simulation results reasonably approximate measured pipeline performance and an initial pipeline state is defined. Only then can the model be used in a predictive mode to test the feasibility of an operating plan.

BUSINESS PROCESSES

Integration of SCADA systems with business applications has long been done. These efforts took on added importance as regulatory changes during the last decade dramatically altered the role of the interstate pipeline [4]. To cope with the changes, interstate pipelines invested considerable resources into upgrading their SCADA systems and increasing the number of points at which telemetered measurement is installed. SCADA data have proven to be an important resource not only for managing pipeline operations but managing the business, as well.

SCADA data are useful in minimizing the impacts of measurement malfunctions that can lead to accounting mistakes and errant customer billing. The same measurement facility is typically used to provide SCADA data and electronic measurement data used in custody-transfer calculations. Pipeline controllers can respond timely to alarms that indicate flow rates are outside the optimal range for measurement accuracy. Other measurement and communication failures are alarmed as well. Responding to these failures early on minimizes inefficiencies later in the business process.

Nominated receipts and deliveries are compared with measured quantities from the SCADA system to determine variances between actual and scheduled activity. At times these variances are planned so as to mitigate the impacts of facility work or to offset imbalances that have accrued over time. At other times, these variances aggravate existing imbalances, in which case adjustments to nominations may be required.

During critical operating conditions, for instance extremely cold weather, variances take on added significance for pipeline and customer alike. Pipelines must receive all scheduled receipt volumes to ensure adequate supply to meet demand. Customers must be apprised of failing supplies and excessive deliveries so attempts can be made to avoid potential penalties. Instead of simply reviewing the previous day's and month-to-date activity, variances are calculated based upon current flow rates and projections for the balance of the day.

TRAINING

A promising approach to training pipeline controllers is to use the SCADA system in conjunction with transient simulations. The trainee interacts with the same SCADA displays and control systems used in actual operations. Simulation results take the place of measured data but all else remains the same. A single training environment meets multiple objectives including familiarization with SCADA system functional capabilities, pipeline operating characteristics and problem solving strategies.

DESIGN

Design studies are based upon simulations that are run with pipeline models. SCADA data are used in model preparation and tuning as well as in design simulations. Simulation results are compared to archived SCADA data to verify the consistency of the model with the physical system and to tune modeling parameters such as pipeline and compressor efficiencies. Projected system modifications are incorporated into the model and design simulations are run. Oftentimes archived SCADA data are used to develop typical demand profiles and other operating conditions to evaluate the response of the modeled system to expected operating conditions.

CONCLUSIONS

The data from supervisory control and data acquisition systems are indispensable to monitoring and controlling operations of interstate natural gas pipelines. Beyond these basic functions, however, the data gathered by these systems are used extensively directly and indirectly in a variety of business applications from design to invoicing.

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BIOGRAPHY

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